Alternative and Renewable Fuel and Vehicle Technology Program

Consultant Report

CONSIDERATIONS FOR CORRIDOR DIRECT CURRENT FAST CHARGING INFRASTRUCTURE IN CALIFORNIA

Final Version

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ABSTRACT

This document, *Considerations for Corridor Direct Current Fast Charging Infrastructure in California,* provides the California Energy Commission and other interested stakeholders with an assessment of the existing state of the direct current fast charging infrastructure within California. Several conclusions are made in this document that lead to recommendations for funding public and private DC fast charger infrastructure improvements.

To date, numerous researchers have produced extensive volumes of accurate and relevant plug-in electric vehicle infrastructure information. This information has been developed through primary research, study, and examination. Alternative Energy Systems Consulting provides a pragmatic assessment of all the available and relevant information to draw practical and actionable conclusions. The authors gathered information and data from multiple sources, which include document research, subject matter expert interviews, stakeholder workshops, and Energy Commission archives. Collected information was then assembled and, in conjunction with extensive consulting experience, prioritized to arrive at practical recommendations.

Alternative Energy Systems Consulting examined three major areas:

- The identification of significant corridor gaps in the existing DC fast charger infrastructure for consideration by the Energy Commission
- The evaluation of infrastructure requirements that should be considered by the Energy Commission, such as site requirements, solar generation, battery storage, and maintenance needs
- The determination of funding requirements and business strategy recommendations.

Keywords: California Energy Commission, NREL, fast charging, DCFC, corridors, corridor gaps, BEV, PEV, PEV infrastructure, IOU, EVSE, EVSP, electric vehicle charging, CHAdeMO, CCS, SAE Combo, CalEV, WCEH, WCGH

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EXECUTIVE SUMMARY

Introduction and Background

In March 2012, California Governor Edmund G. Brown Jr. issued Executive Order B-16-2012 to encourage the successful development of zero-emission vehicles and related infrastructure to "protect the environment, stimulate economic growth, and improve quality of life in the State."

Through more than five decades of determined effort, the State of California has become a global leader in creating emissions legislation and air quality benchmarks that have made efficient gas-powered vehicle design an imperative. These standards have led to a dramatic improvement in environmental and public health, greater quality of life, and bluer, cleaner skies.

As indicated in the executive order and the subsequent *Zero-Emission Vehicle Action Plan*, the next step for Californians is to fundamentally transform the state's transportation systems by moving from internal combustion to zero-emissions vehicles. This project seeks to create a clear path to achieving the electric vehicle charging infrastructure envisioned in the executive order.

Continuing the momentum established by the executive order, the Governor's *2013 Zero-Emission Vehicle Action Plan* and subsequent *2015 ZEV Action Plan Update* identified specific actions required to achieve the goal of 1.5 million zero-emission vehicles on California roads by 2025. The plan contained interim milestones, including fast charging infrastructure to support 1 million vehicles by 2020.

The various goals within the plan were divided into component actions and strategies and then assigned to appropriate state agencies. The California Energy Commission was assigned the task of supporting the strategic development of zero-emission vehicle charging infrastructure.

A great deal of foundational work has already been accomplished. In September 2012, the Energy Commission engaged the National Renewable Energy Laboratory to assess the current state of plug-in electric vehicle infrastructure and future recommendations. In May 2014, the National Renewable Energy Laboratory submitted the *California Statewide Plug-In Electric Vehicle Infrastructure Assessment* (CEC-600-2014-003), a comprehensive overview of current charging infrastructure, future needs, and related challenges.

Purpose

In December 2014 the Energy Commission engaged Alternative Energy Systems Consulting to develop an action plan that would prioritize charging locations and guide regional charging infrastructure planning. As part of this plan, the first task was to assess the state of the statewide DC fast charging network and recommend how best to allocate funding to encourage greater development of DC fast charging stations along critical corridors.

Recommendations

Alternative Energy Systems Consulting recommends the following for Energy Commission consideration:

- ***Grant funding for identified corridor gaps.*** Existing and current DC fast charging infrastructure efforts are heavily concentrated in the urban areas. The authors recommend funding sites within corridor gaps that will initially be less commercially viable.
- ***Grant funding levels.*** To adequately seed the infrastructure in the corridor gap regions, Alternative Energy Systems Consulting calculates about 80 sites will require some form of public subsidies. Alternative Energy Systems Consulting estimates it will require between $9.4 million and $14.5 million to adequately cover these costs for the California Electric Vehicle Highway (CalEV) and other priority corridors.
- ***Site requirements.*** The site must meet minimum requirements to satisfy the needs of the plug-in electric vehicle driver and the infrastructure goals. In general, the site must be safe, accessible, convenient, and reliable. These needs should be expressed as compliant/noncompliant in the process. The site should also contain a type and mix of charging stations that will maximize usefulness. Charge de Move (CHAdeMO), Combined Charging Standard (CCS or SAE Combo), and Tesla Super Charger are the three charging standards that are in use in the United States. Tesla vehicles can physically charge at CHAdeMO stations using an adaptor cable.
    - Require that each site include:
        - Option #1 ($140,000 cap)
            - One CHAdeMO DCFC charger.
            - One dual-protocol (CHAdeMO and CSS) DCFC charger.
            - One Level II charger.
            - One expansion location (for future use).
        - Option #2 ($215,000 Cap)
            - Two CHAdeMO DCFC chargers.
            - Two dual-protocol DCFC Chargers.
            - One Level II, dual-port charger.
            - One expansion location (for future use).
- ***Energy and demand management.*** It is recommended that the Energy Commission continue to encourage the integration of renewable generation and energy storage with DC fast chargers to reduce energy and demand charges.
- ***Business structures.*** After reviewing numerous cases and real-world examples, a common theme emerged that suggests business structures can be relatively simplistic or complex as long as they align the interests of the parties involved.

CHAPTER 1: DCFC Gaps

A significant effort is underway to site, develop, and implement direct current fast charging (DCFC) stations throughout California. Much of this effort was performed under Phases I and II of the Energy Commission's Three-Phase PEV (plug-in vehicle) Infrastructure Deployment Strategy[1]. Entities such as eVgo (NRG), Green Charge Networks, NEDO, AeroVironment, Tesla, Chargepoint, and CarCharging Group (Blink Assets) are planning and installing DCFC equipment under a variety of unique operational mandates. For example, NRG is servicing part of a settlement stemming from the 2001 energy crisis (against NRG predecessor Dynegy) by installing 200 public fast chargers. The New Energy and Industrial Technology Development Organization (NEDO)[2], a Japanese consortium, is working with Nissan and the California Governor's Office to demonstrate and install DCFC equipment and infrastructure. Other collaborations, such as Chargepoint, BMW, and VW, have recently announced intentions to install fast charging equipment along both of the high-demand corridors on the West and East Coasts of the United States[3]. Furthermore, California's electric investor-owned utilities (San Diego Gas & Electric Company, Southern California Edison, and Pacific Gas and Electric Company) have recently submitted applications to the California Public Utilities Commission (CPUC) to become purveyors of electric vehicle charging.

While these efforts will increase the number of DCFC stations in California, the primary focus to date has been within large urban centers. This focus has resulted in significant gaps in interregional corridors.

Gap Focus

Electric vehicle supply providers (EVSPs) have traditionally made a business case by charging usage fees or by taking advantage of subsidized free charging provided by the government and automakers. Typically any collected revenues minimally offset operational and maintenance costs. For this reason, these arrangements work best in areas where DCFC usage is high, as illustrated in the Energy Commission's electric vehicle charging map. Figure 1 shows high concentrations of DC charging capacity in the major cities and adjacent counties of San Francisco, Oakland, San Jose, Sacramento, Los Angeles/Orange County, and San Diego.

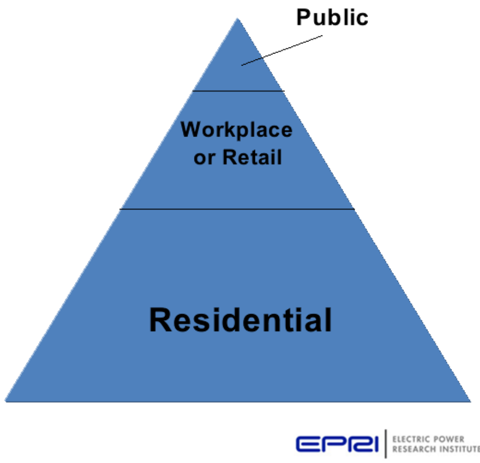
1 http://www.energy.ca.gov/2014publications/CEC-100-2014-001/CEC-100-2014-001-CMF.pdf, page 44.
2 http://www.nedo.go.jp/english/.
3 http://www.chargepoint.com/press-releases/2015/0122.

Figure 1: Current and Planned DCFC Sites

Source: *Alternative Energy Systems Consulting*

The Electric Power Research Institute (EPRI) charging pyramid illustrates the relative amount of charging among home, workplace, and public venues (Figure 2). Most charging occurs at home and in the workplace. There are real and perceived needs, however, associated with public charging that are important to consider.

Figure 2: The Charging Pyramid



Source: EPRI

Recent surveys presented at the January 2015 Energy Commission ZEV Infrastructure Workshop[4] suggest that actual implementation may be even more skewed away from public charging (Level 2 and DCFC) than the EPRI pyramid would suggest. Considering the current typical range of a battery electric vehicle (BEV) is about 80 miles, both real and perceived range limitations exist when public access charging infrastructure is limited. Moreover, the "public charging need" perception is an authentic phenomenon and is partially responsible for the notion of BEV "range anxiety."

BEV drivers need the security of a comprehensive charging network to feel comfortable taking trips beyond typical daily commutes. Many EV advocates and early adopters that were interviewed expressed a vision of being able to take "leisure trips" to such places as Lake Tahoe or Las Vegas. A comprehensive DCFC network focused on public areas outside urban centers is a key hurdle that must be overcome before mass adoption can become a reality.

Corridors

For this paper, corridors are interregional and interstate highway connectors. Corridors allow BEV drivers to travel between urban centers and destination areas. Key corridors must be

4 http://www.energy.ca.gov/2013-ALT-01/documents/index.html#01282015.

identified to construct a comprehensive DCFC infrastructure. DCFC stations must be sited along these corridors at specified geographical distances to provide a useful charging backbone. Other conditions that affect EV battery range, such as increased consumption due to changes in elevation, must be considered when evaluating distances between charging stations.

Stretches within the corridors are typically rural and underserved by existing DCFC infrastructure. It is anticipated that these areas will experience minimal usage until significant BEV market penetration occurs. Based on interviews with EV experts, usage is expected to increase over the next 5 to 10 years, based on the “build it and they will come” theory.

Since developing a commercial business case based solely on charger use fee collection is challenging, these rural and underserved areas will need the most initial public support.

With the possible exception of Tesla, the EV industry appears to lack the motivation to site DCFCs beyond metropolitan areas. To counteract these market forces, public agencies should concentrate funding on hard-to-reach corridors and rural sites. This focus will have the added side benefit of increasing PEV adoption in areas that often lack public transit and a sustainable transportation model.

DCFC Corridor Gap Analysis

AESC’s first task was to identify and prioritize the current corridor gaps using data from UC Davis and NREL. UC Davis developed a sophisticated geographic information system-based (GIS) mapping system that identifies current and future DCFC demand. NREL developed a comprehensive GIS-based mapping system that identifies predicted corridor traffic volume. For this exercise, AESC used the UC Davis map to develop an initial set of corridors and rankings for further consideration. AESC then used the NREL traffic map to refine and prioritize the selected corridors.

The UC Davis model incorporates EV ownership location, existing charger usage, traffic patterns, vehicle range, and other key inputs. The results are regional usage intensity maps that can be used to identify areas with underserved DCFC charging station demand. AESC developed a corridor ranking system based on this predicted future demand and two additional criteria: the extent of existing charging infrastructure; and the proximity to a key north-south highway corridor. Each of the three criteria was evaluated on a scale of 0 to 1. Every interstate, highway, and state route that showed potential for future usage was evaluated on a county-by-county basis. The resulting values for the three criteria were weighted equally and summed, resulting in an overall scale of 0 to 3 for each segment. The higher the score, the greater the potential is for the DCFC to serve unmet demand.

These segment data were then “rolled up” into interregional corridors so that they could be ranked and compared. For example, the State Route 99 Sacramento-to-Fresno interregional corridor traverses five counties: San Joaquin, Stanislaus, Merced, Madera, and Fresno. (See Table 1 below.) AESC evaluated each county section independently and then averaged all counties within an interregional corridor into a combined ranking.

Table 1: Example of County "Roll-Up" Into Interregional Corridor

Corridor	County	Readiness Region	Route	State Position	Locations Along Route	Rank
SR 99 Sacramento to Fresno	San Joaquin	San Joaquin Valley	SR 99	Central	Lodi	**2.42**
SR 99 Sacramento to Fresno	Stanislaus	San Joaquin Valley	SR 99	Central	Modesto, Turlock	**2.75**
SR 99 Sacramento to Fresno	Merced	San Joaquin Valley	SR 99	Central	Merced, Atwater	**2.00**
SR 99 Sacramento to Fresno	Madera	San Joaquin Valley	SR 99	Central	Chowchilla, Madera	**2.00**
SR 99 Sacramento to Fresno	Fresno	San Joaquin Valley	SR 99	Central	Fresno, Selma, Kingsburg	**2.42**
					SR 99 Sacramento to Fresno Combined	**2.32**

Source: *Alternative Energy Systems Consulting*

The NREL model incorporates Federal Highway Administration (FHWA) traffic data to determine accessibility or "visibility" to potential PEV drivers. AESC used the data to validate the routes identified in the initial analysis and to obtain final prioritization. The resulting dataset was used to form the basis of corridor recommendations.

Identifying and Selecting Corridor Gaps

California is large and diverse. Microregions have unique requirements based on available resources and natural surroundings. For these reasons, it made sense to split the initial analysis into northern, central, and southern sections so that each region can be addressed specifically and consistently.

The authors identified applicable corridors using heat maps developed by UC Davis. The maps predict future PEV usage based on traffic patterns, EV concentrations, vehicle range, and existing infrastructure, among other metrics. AESC identified and categorized all the corridors that showed at least 5 percent of predicted future EV demand.

AESC used the UC Davis data, current infrastructure, and road type to develop a simplified trade study and weight the various corridor gaps (1 high – 4 low). The weighting process provided an objective, first-pass comparison of the corridor gaps based on the criteria described above.

Category level thresholds were chosen at natural breaks in the data. Corridors within the first level reside primarily along north-south routes and are potentially part of the California north-south corridor connection to the West Coast Electric Highway (WCEH) in Oregon and Washington. For this report, the authors will refer to this particular route as the "CalEV highway." The second level consists of corridors that have high future demand and low existing infrastructure. Levels 3 and 4 include corridors that are less traveled or have higher levels of existing charging infrastructure.

AESC used the results to determine an initial list of targeted corridor gaps. Based on feedback from various experts, AESC selected corridors from the first two levels for further consideration. Tables 2 through 4 identify the full sets of corridor gaps excluding the metropolitan and predicted near-zero usage areas.

Table 2: Initial Full Set of Northern Corridor Gaps

Section	Northern Corridors	Rating	Priority
North	I-5 Redding to Sacramento	2.67	1
North	I-5 Oregon to Redding	2.58	1
North	SR 99 Red Bluff to Sacramento	2.33	1
North	I-5 Sacramento to Stockton	2.29	1
North	US 50 Lake Tahoe to Sacramento	1.75	2
North	I-80 Sacramento to Reno, NV	1.67	2
North	SR 36 Fortuna to Red Bluff	1.67	2
North	SR 70 Marysville to Oroville	1.67	2
North	SR 70 Oroville to US 395	1.58	2
North	I-205/I-580 Dublin to Tracy	1.58	2
North	SR 88 Nevada (near Carson City) to Stockton	1.53	2
North	US 101 Oregon Border to Garberville	1.50	3
North	SR 53 Clearlake	1.50	3
North	SR 20 Redwood Valley to Yuba City	1.50	3
North	SR 20 Smartsville to Tahoe NF	1.50	3
North	SR 89 Mt Shasta to Lassen Volcanic NP	1.50	3
North	SR 3 Douglas City to SR 36	1.50	3
North	US 199 Cerscent City to Oregon Border	1.50	3
North	SR 16 Woodland to Wilbur Hot Springs	1.50	3
North	SR 162 Willows to Orville	1.50	3
North	SR 175 Middletown to Clearlake	1.50	3
North	SR 4 Stockton to Stanislaus NF	1.50	3
North	SR 44 Lassen Volcanic NP to Redding	1.50	3
North	I-505 Vacaville to I-5 Corridor	1.46	3
North	SR 4 Discovery Bay to Stockton	1.46	3
North	SR 12 Fairfield to Lodi	1.46	3
North	SR 49 Nevada City to Sonora	1.45	3
North	SR 299 Arcata to Weaverville	1.44	3
North	SR 65 Olivehurst to Roseville	1.42	3
North	SR 17 San Jose to Santa Cruz	1.33	3
North	I-80 Vallejo to Sacramento	1.33	3
North	SR 49 Chilcoot-Vinton to Nevada City	1.33	3
North	US 97 Weed to Oregon Border	1.33	3
North	SR 113 Davis to Woodland	1.25	4
North	SR 1 Leggitt to Sausalito	1.25	4
North	US 395 Oregon Border to Reno, NV	1.25	4
North	SR 29 Lakeport to Calistoga	1.21	4
North	US 101 Garberville to Sausalito	1.21	4
North	SR 128 Albion to Winters	1.19	4

Source: *Alternative Energy Systems Consulting*

Table 3: Initial Full Set of Central Corridor Gaps

Section	Central Corridors	Rating	Priority
Central	SR 99 Sacramento to Fresno	2.32	1
Central	I-5 Stockton to Wheeler Ridge	2.28	1
Central	SR 99 Fresno to Wheeler Ridge	2.25	1
Central	US 395 Nevada Border to Hesperia	1.67	2
Central	US 101 San Jose to San Miguel	1.54	2
Central	SR 120 Oakdale to Lathrop	1.54	2
Central	SR 108 Sonora to Bridgeport	1.50	3
Central	SR 152 Watsonville to Fairmead	1.31	3
Central	SR 140 Mariposa to Yosemite Valley	1.25	4
Central	SR 156 Hollister	1.25	4
Central	SR 180 Mendota to Kings Canyon NP	1.25	4
Central	SR 43 Selma to Bakersfield	1.25	4
Central	SR 168 Fresno to Huntington Lake	1.25	4
Central	SR 65 Exeter to Oildale	1.25	4
Central	SR 132 Modesto to Coulterville	1.25	4
Central	SR 190 Tipton to Sequoia	1.25	4
Central	SR 198 Fresno to Sequoia	1.25	4
Central	SR 1 Santa Cruz to SLO	1.25	4
Central	SR 41 Oakhurst to Morro Bay	1.19	4

Source: *Alternative Energy Systems Consulting*

Table 4: Initial Full Set of Southern Corridor Gaps

Section	Southern Corridors	Rating	Priority
South	I-5 Oceanside to San Clemente	2.50	1
South	I-5 Wheeler Ridge to Santa Clarita	2.42	1
South	I-40 Barstow to Needles	1.67	2
South	SR 18 Apple Valley to Lucerne Valley	1.67	2
South	I-15 San Bernardino to Nevada	1.58	2
South	SR 14 Santa Clarita to Inyokern	1.58	2
South	SR 111 Salton Sea to El Centro	1.50	3
South	SR 86 Indio to Brawley	1.50	3
South	I-10 Palm Springs to Blythe	1.50	3
South	SR 138 Palmdale to Cajon Pass	1.50	3
South	SR 78 Carlsbad to Salton Sea	1.42	3
South	I-8 El Cajon to Yuma, AZ	1.42	3
South	SR 178 Ridgecrest to Panamint	1.42	3
South	SR 905 Nestor to International Border MEX	1.42	3
South	SR 33 Ventura to Coalinga	1.38	3
South	US 101 San Miguel to Thousand Oaks	1.28	3
South	SR 126 Ventura to Santa Clarita	1.25	4
South	SR 166 Santa Maria to Tejon	1.25	4
South	SR 138 Hungary Valley to Lancaster	1.25	4
South	SR 46 Wasco to Paso Robles	1.25	4
South	SR 76 Oceanside to Lake Henshaw	1.25	4
South	SR 23 Thousand Oaks to Simi Valley	1.25	4
South	SR 1 Arroyo Grande to Gaviota	1.21	4
South	SR 58 Santa Margarita to Barstow	1.17	4
South	I-10 Riverside to Palm Springs	1.08	4
South	I-215 Murrieta to Riverside	1.08	4
South	I-15 Riverside to San Bernardino	1.08	4
South	SR 246 Santa Ynez to Lompoc	1.00	4
South	SR 154 Santa Barbara to Los Olivos	1.00	4

Source: *Alternative Energy Systems Consulting*

Categorizing and Prioritizing Selected Corridor Gaps

AESC then worked with NREL to coordinate and prioritize these data with NREL's heat maps. The NREL maps use a "visibility" metric[5] developed from FHWA average annual traffic count data and Polk automotive sales data. This allowed AESC not only to confirm initial results, but to refine corridor prioritization based on federal data.

Interviewed experts tended to agree on 25- to 50-mile charge station spacing as the most appropriate for today's BEV ranges. NREL and AESC used a midpoint, 33-mile[6] geographical spacing in the analysis. As such, corridors were evaluated using 33-mile intervals except in cases where elevation and weather are a consideration, in which case the spacing was reduced appropriately. While closer spacing between stations would improve reliability of access for drivers, the total costs must be considered. Therefore, AESC recommends that the Energy Commission focus on seeding the infrastructure effort on many corridors rather than focus on being comprehensive on a few. Once stations are installed, the increased activity will have the effect of fostering new commercial opportunity in developing additional infrastructure.

AESC considered the extended range on the anticipated release of new BEVs such as the Chevrolet Bolt[7]. While the increased range will reduce the need for certain kinds of additional infrastructure, the full impact of the advanced technology will take many years to be realized. Increased demand for PEVs resulting from new models and bigger batteries will, in turn, increase the demand for charging stations on interregional corridors. Distributed charging provides a benefit in both low-adoption and high-adoption scenarios as dispersed resources will foster more choices for EV drivers.

In the initial analysis, all corridors were assessed concurrently with the CalEV highway connection routes, given a slight priority in the weighting algorithm. After discussion with the Energy Commission and other stakeholders regarding the importance of the California north-south corridor, it was decided to split the CalEV highway and "Other" routes and analyze them separately.

CalEV Highway

The CalEV highway is defined as the north-south route from the Oregon border to the Mexico border. In Northern and Southern California, Interstate 5 (I-5) is the main artery for vehicle travel. However, within parts of the Sacramento Valley and San Joaquin Valley, there is another major freeway that runs parallel to I-5 known as State Route 99 (SR 99), and both routes offer attractive options for the CalEV.

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5 The visibility metric indicates corridors with the largest volume of traffic, where DCFC stations would be accessible or "visible" to the most drivers.
6 NREL and AESC used 33 miles as a midrange value between 25-50 miles in the initial analysis. This value was used to determine the estimated number of required stations.
7 Chevrolet Bolt electric vehicle (See http://www.chevrolet.com/culture/article/bolt-ev-concept-car.html.)

In the authors' analysis, AESC split the I-5 and SR 99 corridors into five segments starting at the Oregon border: 1) Oregon to Red Bluff, 2) Red Bluff to Sacramento, 3) Sacramento to Fresno, 4) Fresno to Wheeler Ridge (near the Grapevine), and 5) Wheeler Ridge to Santa Clarita. The analysis omitted the three major metro areas (Sacramento, Los Angeles/Orange County, and San Diego).

Table 5 illustrates the corridor routes by segment and the number of recommended sites (additional sites). The corridors were not prioritized because all routes are seen as critical infrastructure to the effort. The NREL visibility metrics are included for comparison. Alternate SR 99 routes were selected over the I-5 routes in segments two and three (Sacramento and San Joaquin Valleys). An explanation of the rationale behind this decision is in the ***Interstate 5 or State Route 99*** section on page 18.

Table 5: Recommended CalEV Highway DCFC Sites

Segment	Map Label	Section	Corridors	Approx. Miles	DCFC Locations (1 per 33 miles)	NREL Visibility Metrics		AESC Analysis	
						FHWA VMT	FHWA VMT/mile	Existing or Planned Sites	Additional Sites
1	I-5 RBF:OR	North	I-5 Oregon to Red Bluff	142	4	1,942,986	13,683	0	7
2	I-5 SAC:RDD	North	I-5 Redding to Sacramento	162	5	4,233,410	26,132	0	4
City	Sacramento								
3	99 SAC:FAT	Central	SR 99 Sacramento to Fresno	177	5	11,654,731	65,846	5	3
4	99 FAT:GVN	Central	SR 99 Fresno to Wheeler Ridge	140	4	7,930,504	56,646	3	3
5	I-5 GVN:SCT	South	I-5 Wheeler Ridge to Santa Clarita	56	2	3,993,131	71,306	1	3
City	Los Angeles/Orange County								
City	San Diego								

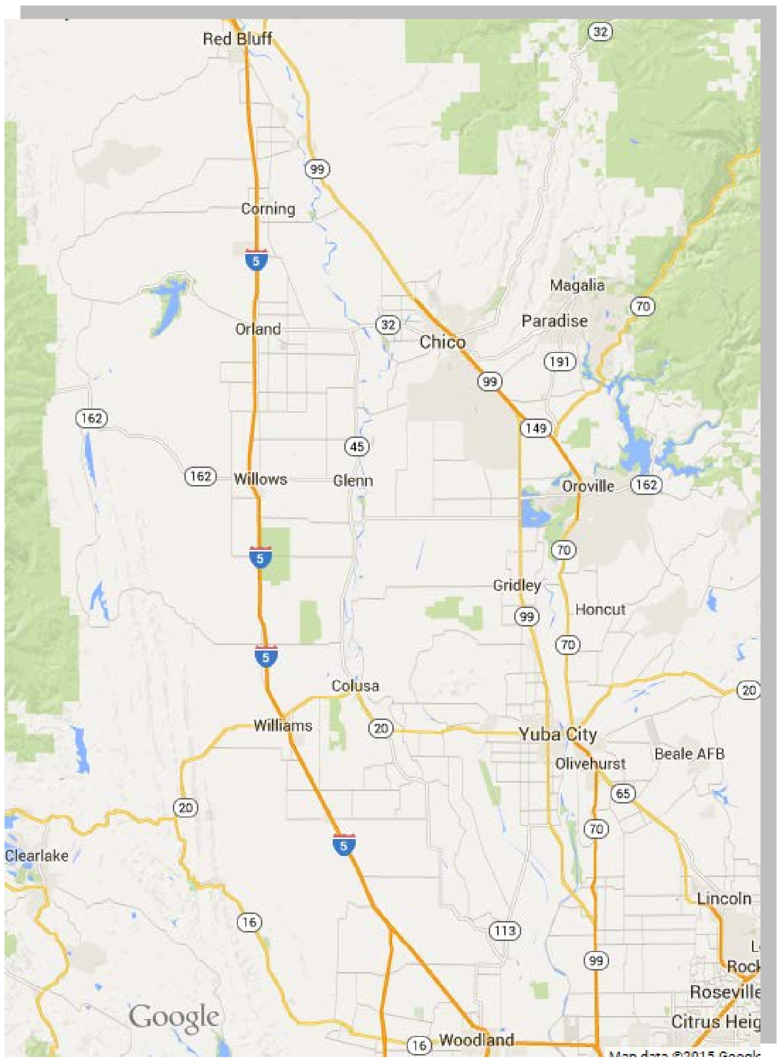
Source: *Alternative Energy Systems Consulting*

Interstate 5 or State Route 99

The CalEV highway could adequately navigate I-5 or SR 99 through the San Joaquin and Sacramento Valleys. The total travel distance from Red Bluff to Sacramento is 131 miles on I-5 and 127 miles on SR 99. The total travel distance from Sacramento to Wheeler Ridge is 306 miles on I-5 and 307 miles on SR 99.

Through the Sacramento Valley, SR 99 travels through the more densely populated cities on the eastern section and intersects Yuba City and Chico. The I-5 route traverses through the more rural agricultural landscape of the western side of the Sacramento Valley. Figure 3 illustrates this point.

Figure 3: Sacramento Valley Corridors

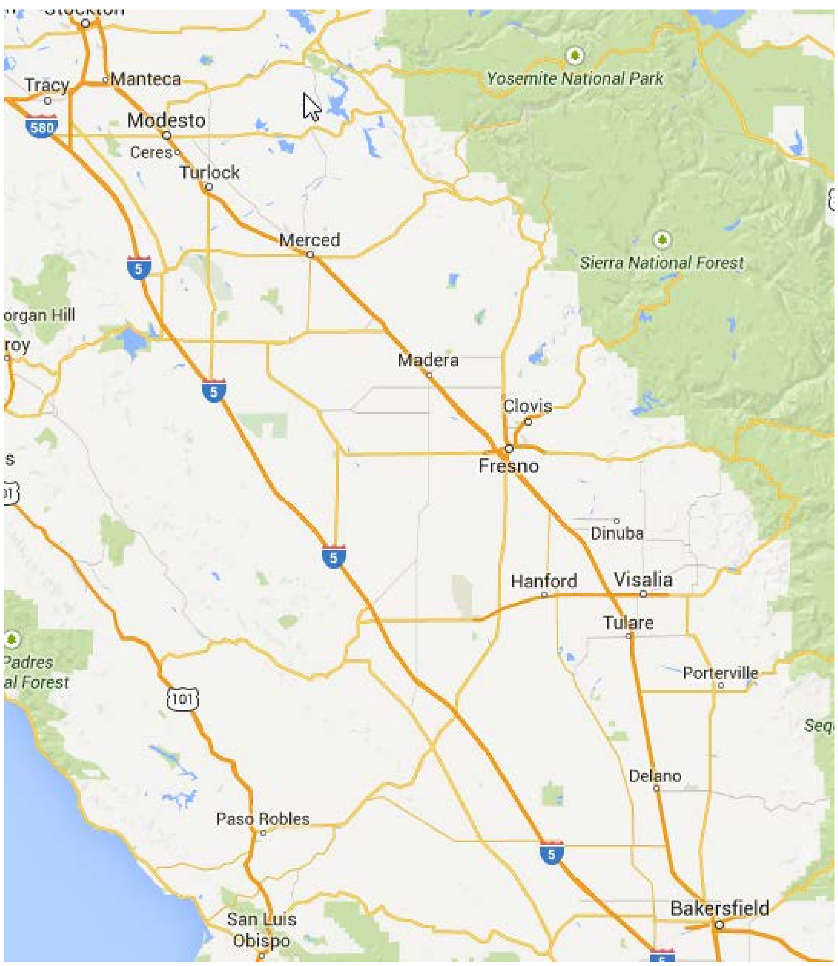


Source: Google Maps

Traffic on I-5 is anticipated to be twice the volume of the SR-99, according to the NREL visibility metrics. This is likely because I-5 is a more direct route for interstate traffic. The utility-level infrastructure is roughly equivalent for the two corridors, but the SR 99 route travels through more densely populated urban centers. The SR 99 route offers potentially more site candidates with a higher level of available amenities/conveniences and a higher likelihood of site electrical infrastructure necessary for DCFC operations. Based on usage potential and the outreach objectives of the CalEV, however, the significantly higher level of EV visibility and latent public awareness must take precedence over optimal siting. As a result, AESC recommends prioritizing I-5 over SR 99 for CalEV designation in the Sacramento Valley.

Through the San Joaquin Valley, SR 99 travels through the more densely populated eastern section, including Bakersfield, Visalia, Fresno, Madera, Merced, and Modesto. The I-5 route passes through a prevalence of rural agricultural landscape on the western side of the San Joaquin Valley, as Figure 4 illustrates.

Figure 4: San Joaquin Valley Corridors



Source: Google Maps

The traffic is higher on SR 99 in the San Joaquin Valley, according to the NREL visibility metrics, and based on existing infrastructure, fewer additional DCFCs are required. Local PEV drivers would also have greater access to recharging at the corridor DCFC stations. For these reasons, AESC recommends prioritizing SR 99 over I-5 in the San Joaquin Valley.

Segment 1 – Oregon Border to Red Bluff

Segment 1 covers I-5 travel from the Oregon border to Red Bluff. AESC estimates that this corridor will require seven DCFC sites to adequately serve the projected BEV traffic. The southernmost site, Red Bluff, is covered in the subsequent segment. The *Upstate PEV Regional Readiness Plan* [8] has a detailed analysis of this corridor. One particular area of concern is the increased grade traveling from Redding to the city of Mt. Shasta. The elevation change is about 3,000 feet and increases the rate of depletion on the EV batteries. For this reason, the typical site separation distance must be considered closer to the 25-mile lower range. Mt. Shasta has one Tesla charging station. Because these chargers are proprietary to Tesla vehicles, the authors did not include them in the analysis.

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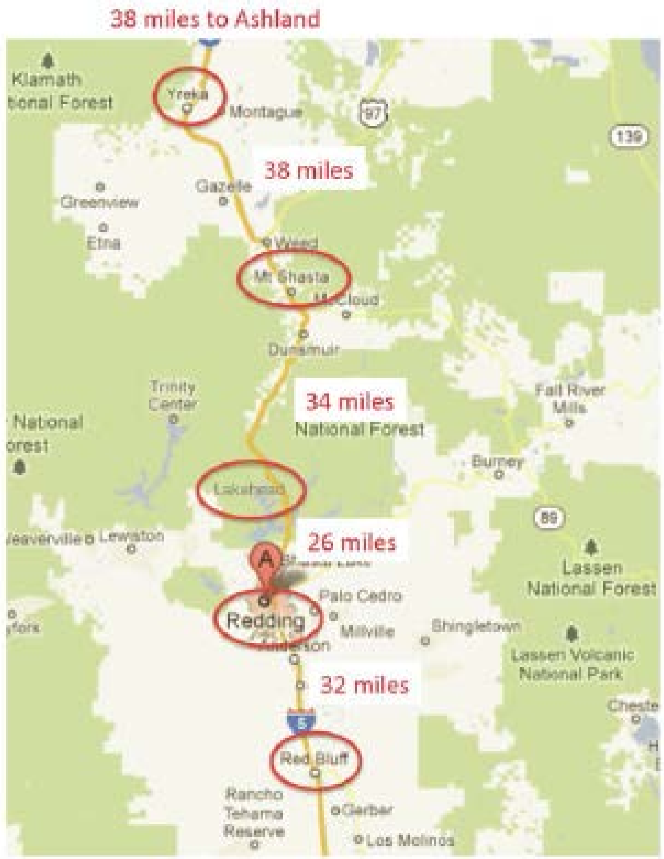
8 (source: http://static1.squarespace.com/static/53764d9fe4b0cb63d6f97b20/t/546bbf05e4b02cdf60e99f49/1416347462203/Readiness+Plan)

Figure 5: Upstate Region Population Centers With <40-Mile Range



Source: *The Upstate PEV Regional Readiness Report*

AESC performed a top-level infrastructure analysis using Google Maps. According to these results, corroborated by the readiness plan, the potential siting locations include (all sites require additional chargers):

- Yreka
- Weed
- Mt. Shasta
- Dunsmuir
- Lakehead
- Redding
- Anderson

Segment 2 – Red Bluff to Sacramento

Segment 2 covers travel on I-5 from Red Bluff to Sacramento. AESC estimates that the I-5 route will require an additional four sites.

AESC performed a special analysis of the electrical infrastructure on this corridor to ensure the required power was available throughout the rural sections. (See Table 6.) AESC reviewed substation capacity, feeder capacity, and existing commercial infrastructure to assess the general siting potential. This additional task was performed on this segment to evaluate the I-5 and SR 99 alternates. The authors' analysis indicates that there is adequate three-phase 480 volt power on both routes. This level of power is required by most DC fast chargers to operate effectively. This analysis also allowed the authors to determine appropriate siting locations and numbers. The potential siting locations include (all sites require additional chargers):

- Red Bluff.
- Orland.
- Williams.
- Woodland.

Table 6: Electrical Infrastructure for Sacramento Valley Alternate CalEV Highway Routes

Location				Substation			Feeder					Site		
Section	Highway	DCFC Location (Interchange/Intersection)	Utility	Nearest Substation	Highest Voltage	Nominal Voltage	Nearest Feeder	Size	Capacity (MW)	Project Peak Capacity	Available Capacity	Distance Between 3P and DCFC	Distance from previous stop	Nearby Commercial Activity
Sacramento Valley	I-5	Capital Mall	SMUD	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Sacramento Valley	I-5	Woodland - East Main St.	PG&E	Woodland	115kV	12kV	Woodland 1106	12kV	11	6.86	4.14	0	17	Shopping Center
Sacramento Valley	I-5	Williams - SR20	PG&E	Williams	60kV	12kV	Williams 1102	12kV	12.94	6.64	6.3	0	40	Motel
Sacramento Valley	I-5	Orland - SR32	PG&E	Orland B	60kV	12kV	Orland Station B 1101	12kV	7.64	4.15	3.49	0	42	Fast Food
Sacramento Valley	I-5	Red Bluff - SR36	PG&E	Red Bluff	60kV	12kV	Red Bluff 1105	12kV	10.4	8.89	1.51	0	30	Mall
Sacramento Valley	SR 99	Capital Mall	SMUD	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Sacramento Valley	SR 99	North Sac - Del Paso	SMUD	Natomas	230kV		1204	12kV				0	7	Fast Food/Hotel/Sports
Sacramento Valley	SR 99	Yuba - SR20	PG&E	Harter	60kV	12kV	Harter 1104	12kV	12.94	10.06	2.88	0	36	Mall
Sacramento Valley	SR 99	Gridley - East Gridley Rd	PG&E	Honcut	115kV	12kV	Honcut 1101	12kV	10.8	7.49	3.31	0	16	Mall
Sacramento Valley	SR 99	Chico - East 20th	PG&E	Notre Dame	115kV	12kV	Norte Dame 1101	12kV	12.49	5.72	6.77	0	30	Mall - Existing CHAdeMO at Nissan
Sacramento Valley	SR 99	Red Bluff - SR36	PG&E	Red Bluff	60kV	12kV	Red Bluff 1105	12kV	10.4	8.89	1.51	0	42	Mall

Source: *Alternative Energy Systems Consulting*

Segment 3 – Sacramento to Fresno

Segment 3 covers travel on SR 99 from Sacramento to Fresno. The roads are relatively flat, so the minimum distance spacing applied when selecting site locations was closer to the 50-mile end of the range. AESC estimates that the route will require an additional three sites.

AESC performed a top-level infrastructure analysis using Google Maps. According to these results the potential siting locations include (**bold indicates required additional chargers)**:

- Elk Grove (Energy Commission planned site).
- **Lodi.**
- Stockton East (Energy Commission planned site).
- **Modesto or Turlock.**
- Atwater (existing).
- Merced (Energy Commission-planned site).
- **Madera.**

Segment 4 – Fresno to Wheeler Ridge (the Grapevine)

Segment 4 covers travel on SR 99 from Fresno to Wheeler Ridge. The roads are relatively flat, so the minimum distance spacing applied when choosing site locations was closer to the 50-mile end of the range. AESC estimates that the route will require three additional sites. One CHAdeMO DCFC already exists in Bakersfield. To serve all types of anticipated BEV traffic, however, an additional site needs to be installed in this location.

AESC performed a top-level infrastructure analysis using Google Maps. According to these results, the potential siting locations include (**bold indicates required additional chargers)**:

- Fresno (Energy Commission-planned site).
- **Selma.**
- Tulare (Energy Commission planned).
- **Delano.**
- **Bakersfield** (existing CHAdeMO).
- Wheeler Ridge (Energy Commission planned site).

Segment 5 – Wheeler Ridge to Santa Clarita

Segment 5 covers travel on the I-5 from Wheeler Ridge to Santa Clarita. The road ascends and descends through the Tejon Pass, linking the San Joaquin Valley to Southern California. One particular area of concern is the change in grade traveling from either side of the mountain pass. The elevation change is nearly 2,750 feet, adding to significant drain on the EV batteries. For this reason, the typical site separation distance must be considered closer to the 25-mile end of the range.

AESC estimates that the route will require three additional sites. AESC performed a top-level infrastructure analysis using Google Maps. According to these results, the potential siting locations include (**bold indicates required additional chargers)**:

- Grapevine (Tesla - Lebec; Energy Commission planned site – Wheeler Ridge).
- **Lebec or Gorman.**
- **Castaic.**
- **Santa Clarita.**

"Other" Corridors

Both the UC Davis and NREL heat maps identify additional high-potential EV corridors other than those occurring specifically on the CalEV highway. Many of these "other" corridors are important destination routes or freeway interconnectors. A good example is the Interstate 205/Interstate 580 between Dublin and Tracy. The NREL usage visibility metric for this route is a staggering 119,540 total vehicle miles traveled (VMT) normalized per mile.

As described earlier, AESC created an initial corridor listing from the UC Davis heat maps. NREL separately developed a heat map based on federal highway traffic and Polk BEV ownership data. NREL combined these two analyses to create a comprehensive list of corridors ranked by these visibility metrics. The visibility metric predicts which routes have the highest potential EV usage based on traffic patterns and EV ownership location data. AESC developed a third metric, "perceived driver preference," to incorporate subjective driving preferences expressed by electric vehicle stakeholders such as PEV readiness personnel and BEV advocates. For example, those surveyed expressed an elevated interest in interstate and destination travel. AESC also took into consideration the available infrastructure on the corridor routes. For instance, Interstate 15 in San Bernardino scores high in the priority based on traffic, but it requires six DCFC site locations through some sparsely populated desert passes. This relegates this corridor to a lower priority than what the raw traffic data would suggest.

In the final analysis, the authors removed the three section designations of the state (that is, north, central, and south). This split was intended to allow examination of each section of the state separately on its own merits. Because the perceived driver preference metric was introduced, however, regional and state preferences were comprehensively applied instead.

Table 7 illustrates each corridor and the number of recommended sites. The number of sites is based on a straight 33-mile separation (mean of the 25-50 mile recommended range). AESC used natural breaks in the visibility metrics to establish visibility priority and the subjective ratings in perceived driver preference to develop the perceived driver preference priority. These two values were overlaid using equal weighting to derive a combined priority. As a result, AESC recommends the following corridors in order of priority.

Table 7: "Other" Corridors by Priority

Map Label	Section	Corridors	Approx. Miles	DCFC Locations (1 per 33 miles)	NREL "Visibility" FHWA VMT	FHWA VMT/mile	Visibility Priority	Perceived Driver Preference Priority	Combined	Comments
580 DBN:TCY	North	I-205/I-580 Dublin to Tracy	39	1	4,662,061	119,540	1	1	1	Important connector between Bay Area and Central CA
101 SJC:SMG	Central	US 101 San Jose to San Miguel	148	4	6,784,695	45,843	1	1	1	Connects So. Cal. To Bay Area through the Coast
80 SAC:RNO	North	I-80 Sacramento to Reno, NV	141	4	5,792,203	41,079	1	1	1	Important connector between Urban Center and Reno, NV
50 SAC:LKT	North	US 50 Lake Tahoe to Sacramento	103	3	3,311,508	32,151	1	1	1	Important connector between Urban Centers and Lake Tahoe
120 OKD:YSM	Central	SR 120 Oakdale to Yosemite	90	3	821,356	30,421	1	1	1	Connects I-5/SR99 to Yosemite
10 BMT:BLY	South	I-10 Beaumont to Blythe	148	4	6,700,758	45,275	1	2	1.5	Connects Southern CA to AZ (enroute to Phoenix)
41 LMR:OKR	Central	SR 41 Lemoore to Oakhurst	79	2	3,325,748	42,098	1	2	1.5	Connects Fresno area to the coast
I-5 OSD:SCN	South	I-5 Oceanside to San Clemente	24	1	2,737,629	114,068	1	3	2	Connects San Diego to Orange County
I-15 SBO:NV	South	I-15 San Bernardino to Nevada	182	6	9,547,526	52,459	2	2	2	Connects Southern CA to NV (enroute to Las Vegas)
14 SCT:INY	South	SR 14 Santa Clarita to Inyokern	119	4	4,563,495	38,349	1	3	2	Connects Los Angeles to Palmdale
152 101:99	Central	SR 152 from US 101 to SR 99	83	3	1,998,534	24,079	2	2	2	Connects San Jose area to Central CA
58 BKR:LWD	South	SR 58 Bakersfield to Lenwood	126	4	2,197,902	17,444	1	3	2	Connects Bakersfield to Barstow
10 SRA-EKA	North	US 101 Santa Rosa to Eureka	217	7	3,222,978	14,852	2	2	2	Connects Urban areas to Oregon (Coast Drive)
I-5 SAC:SCK	North	I-5 Sacramento to Stockton	49	1	2,540,891	51,855	2	3	2.5	Less desirable alternate to SR-99 WCEH
I-5 SCK:GVN	Central	I-5 Stockton to Grapevine	252	5	9,528,821	37,813	2	3	2.5	Less desirable alternate to SR-99 WCEH
99 SAC:RBF	North	SR 99 Red Bluff to Sacramento	132	4	2,329,975	17,651	2	3	2.5	Less desirable alternate to I-5 WCEH
12 FRF:LDI	North	SR 12 Fairfield to Lodi	47	1	857,368	18,242	2	3	2.5	Connects upper Bay to Lodi/Stockton
49 AUB:GRS	North	SR 49 Auburn to Grass Valley	24	1	498,749	20,781	2	4	3	Alternate to I-80
505 VCA:I-5	North	I-505 from Vacaville north to I-5	32	1	520,953	16,280	2	4	3	Connects I-80 to I-5 (Bypasses Sacramento)
8 ECJ:YUM	South	I-8 El Cajon to Yuma AZ	158	5	3,079,815	19,492	2	5	3.5	Connects San Diego to AZ (Yuma)
86 IDO:ECR	South	SR 86 Indio to El Centro	86	3	1,243,981	14,465	3	4	3.5	Connects Palm Springs to El Centro
395 HPA:NV	Central	US 395 Nevada Border to Hesperia	209	6	2,937,417	14,055	2	5	3.5	Connects Southern CA to Eastern CA (Close to NV border)
40 BSW:NED	South	I-40 Barstow to Needles	144	4	1,558,077	10,820	3	4	3.5	Connects Barstow to AZ (Needles)
70 MVL:ORO	North	SR 70 Marysville to Oroville	39	1	303,732	7,788	3	4	3.5	Alternate route to Reno
88 SCK:CRC	North	SR 88 Carson City, NV to Stockton	127	4	735,301	5,790	3	4	3.5	Alternate Route to Carson City/Tahoe (Originating in Stockton)
36 RBF:FTA	North	SR 36 Fortuna to Red Bluff	132	4	0	0	4	3	3.5	Connects upper coast to Central thoroughfares
70 ORO:395	North	SR 70 Oroville to US 395	136	4	75,694	557	4	4	4	Alternate route to Reno
18 AVL:LUC	South	SR 18 Apple Valley to Lucerne Valley	24	1	5,727	239	4	4	4	Connects San Benardino to Mountain Resorts

Source: *Alternative Energy Systems Consulting*

CHAPTER 2:
DCFC Infrastructure Requirements

Site Requirements

The selected locations must meet a minimum level of criteria to satisfy the needs of the site host, the PEV client, and the infrastructure goals. Selected locations, whether privately or publicly owned, must be safe, accessible, convenient, and reliable.

Configuration

Based on conversations with various experts, AESC recommends two options for site configuration.

Table 8: Charging Station Configuration

Equipment	Option 1 Quantity	Option 2 Quantity
Level 2 Charger (single port)	1	0
Level 2 Charger (dual port)	0	1
CHAdeMO DCFC (single port)	1	2
Dual Protocol DCFC	1	2
Expansion DCFC (single port)	1	1

Source: *Alternative Energy Systems Consulting*

The dual-protocol DCFC is configured with both a CHAdeMO and SAE Combo (CCS) connector; however, only one protocol can be used at a time, effectively making it a single-port unit. The DCFCs and the Level 2 chargers should have clearly labeled parking spaces. A colocated Level 2 charger is desirable because it significantly increases the functionality of the charging station with little added cost and serves as a backup in case all DCFCs are in use. It also allows the station to serve local drivers.

AESC chose this mix of charging stations because of the high prevalence of CHAdeMO-based vehicles in California at this time. The configuration for Option 1 allows for two CHAdeMO and one Level 2 or one CHAdeMO, one SAE Combo, and one Level 2 to charge at the same time. Option 2 effectively doubles this capacity.

AESC recommends that each option be associated with a specific per-site funding limit that reflects a reasonable ceiling for expected installation costs. The suggested limit for project sites selecting Option 1 is $140,000, as detailed in Table 9.

Table 9: Recommended Funding Limit for Option 1

Description	Units	Typical Cost per Unit	Total Cost
Site Work (demolition, concrete, mounting, signs, etc.)	1	$10,000	$10,000
General Electrical Work (wire, conduit, etc.)	1	$3,000	$3,000
New 300 kVA Transformer	1	$32,500	$32,500
Extend Utility Service	1	$17,500	$17,500
Level 2 Charger (single port)	1	$7,500	$7,500
CHAdeMO DCFC (single port)	1	$20,000	$20,000
Dual Protocol DCFC	1	$35,000	$35,000
Subtotal			$125,500
10% Contingency			$12,550
Total			$138,050
Recommended Limit for Option 1			**$140,000**

Source: *Alternative Energy Systems Consulting*

For sites where Option 2 is selected, the suggested funding limit is increased to $215,000 to account for increases in material and labor costs.

Table 10: Recommended Funding Limit for Option 2

Description	Units	Typical Cost per Unit	Total Cost
Site Work (demolition, concrete, mounting, signs, etc.)	1	$15,000	$15,000
General Electrical Work (wire, conduit, etc.)	1	$5,000	$5,000
New 500 kVA Transformer	1	$40,000	$40,000
Extend Utility Service	1	$17,500	$17,500
Level 2 Charger (dual port)	1	$10,000	$10,000
CHAdeMO DCFC (single port)	2	$20,000	$40,000
Dual Protocol DCFC	2	$35,000	$70,000
Subtotal			$197,500
10% Contingency			$19,750
Total			$217,250
Recommended Limit for Option 2			**$215,000**

Source: *Alternative Energy Systems Consulting*

The costs used to determine the limits for Options 1 and 2 represent the maximum expected costs of installation and equipment. Specific site conditions, however, may result in significant deviations from estimated costs. Price ranges were determined through a combination of interviews with industry experts and by using information contained in PEV regional readiness reports.

It is expected that a significant portion of the costs will be associated with installing a new transformer to handle the anticipated load for the charging station. A portion of this load includes the eventual installation of a 100-kilowatt (kW) DCFC in the expansion port (stub out), which should be accounted for in the transformer sizing calculations. A rough breakdown of expected transformer size for each option is provided in the following tables, but actual values will vary depending on the choice of equipment selected by the contractor.

Table 11: Transformer Sizing for (a) Option 1 and (b) Option 2

Equipment	Quantity	KVA per Unit	kVA Total
Level 2 Charger	1	10	10
CHAdeMO DCFC	1	65	65
Dual Protocol DCFC	1	65	65
Expansion DCFC	1	130	130
Ancillary	1	5	5
Option 1 Total			275
Next Largest Standard Size			**300 kVA**

(a)

Source: *Alternative Energy Systems Consulting*

Equipment	Quantity	KVA per Unit	kVA Total
Level 2 Charger	2	10	20
50 kW DCFC	4	65	260
Expansion DCFC	1	130	130
Ancillary	1	7.5	7.5
Option 1 Total			417.5
Next Largest Standard Size			**500 kVA**

(b)

Source: *Alternative Energy Systems Consulting*

Location

The site should be within one mile from a highway interchange. It should have appropriate paved parking and reasonable ingress/egress points, as well as sufficient available area to support multiple charging-only spaces.

New Construction

It is simpler to design a new DCFC station from an electrical and accessibility standpoint than retrofit an existing location. For this reason, the authors recommend that new construction sites also be considered.

Facilities

The site should ideally have 24-hour access to a well-maintained and illuminated restroom. The restroom should be supplied with municipal water and have a clean and operable drinking fountain.

Safety

The site should have dusk-to-dawn area lighting and have a reasonable level of activity. The site must also have shelter for inclement weather.

Public Amenities

The site should ideally have basic amenities such as vending, snacks, or fast food. Full-service amenities such as restaurants or retail shopping within a reasonable walking distance are preferred.

Electric Power

Access to existing, nearby 480 V three-phase power is preferable. The local grid must have adequate capacity to serve the site and all the chargers.

Energy and Demand Management

As infrastructure is deployed to support the continued adoption of PEVs, the integration of renewable generation and energy storage play an increasingly important role as a way to address the increasing cost of electricity. While the installation of solar and energy storage increases the upfront cost of EVSE installation, the long-term benefits of reduced demand and energy costs could make the economic case more attractive given current electric rates.

The utilities are looking at various strategies for billing EV charging and have implemented pilot programs that could lead to new electric rate schedules for EVs. However, EV rates for nonresidential customers are available only in SCE territory at this time, and the existing rate structures vary greatly from one utility to another. SCE offers EV rates to its residential and nonresidential customers with the energy costs as high as $0.36/kWh[9] during summer on-peak periods and demand charges ranging from $7.23/kW[10] to $13.20/kW[11]. PG&E and SDG&E customers are billed according to existing rates, which may include demand charges. Demand charges are levied in PG&E when a customer's demand exceeds 200 kW. A customer in PG&E territory whose demand is expected to exceed 200 kW and remain under 50 kW expects to pay

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9 Southern California Edison has three EV rates. TOU EV 3 A & B and TOU EV 4.

10 SCE TOU EV 3 B demand charge during all times of day is $7.23/kW.

11 SCE TOU EV 4 demand charge during all times of day is $13.20/kW.

$0.15/kWh and about $15/kW[12]. In SDG&E territory, if a facility is expected to exceed 20 kW, it will be put on a general service, time-metered rate schedule and will incur demand charges. Otherwise known as AL-TOU[13], this tariff is defined as being applicable to all metered nonresidential customers whose monthly maximum demand equals, exceeds, or is expected to equal or exceed 20 kW. The noncoincident demand (15 minute instantaneous demand unrelated to time of day) charge is about $24/kW, and the peak demand charge is about $10/kW.

Integration of renewable generation—specifically solar photovoltaic (PV) systems—decreases billed energy consumption and helps reduce system electric demand. According to the 2013 EV Project[14] report, the average number of charge events at a public DCFC station per week is about 16, or 2.3 charge events per day, and the majority of charging events required fewer than 12 kWh. Based on the data, the authors find that a PV system would need to produce up to 10,000 kWh per year to satisfy the observed DCFC usage patterns. A 6 kW[15] PV system can produce enough energy to offset the charging requirement and would cost about $16,000[16]. If the site applies the net energy metering[17] (NEM) tariff, all energy generated by the PV system can offset the energy used to charge EVs by generating credits. For example, a PV system this size located in SDG&E territory could help avoid up to $1,000[18] of energy costs and up to $3,600[19] of energy costs in PG&E territory.

Integrating grid-tied energy storage systems also allows for demand reduction benefits. The electric energy stored in the battery energy storage system (BESS) can be supplied by the electric utility during periods when electric rates are the cheapest (off-peak) or supplied by the renewable energy resource (such as PV). BESS can be configured to reduce utility peak, maximum, or noncoincident demand costs by targeting periods of high usage during the day or night. Furthermore, energy storage can be used to limit demand spikes such that a customer is not pushed into a demand metered rate schedule in SDG&E and SCE.

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12 The values stated here are based on PG&E's electric schedule A-10.

13 Schedule AL-TOU time of use tariff

14 EV PROJECT – The EV project enrolled Nissan Leaf and Chevy Volt drivers into the program to analyze their driving and charging behavior. The charging infrastructure includes 200 DCFC, and recent reports speak to the use of them. http://avt.inl.gov/evproject.shtml

15 PVWatts is an online-based software that models the output of solar PV systems. This software was used to calculate the system size required to produce the energy needed to offset energy consumed by the EVs. The DC system size was found to be 6kW and has systems losses of 14 percent, a tilt of 20 degrees, and an azimuth of 180 degrees.

16 PVWatts – $2.60/Wdc; this is the value automatically populated by PVWatts when a commercial PV system is selected.

17 *Net metering* is a billing mechanism that credits solar energy system owners for the electricity they add to the grid. (See http://www.seia.org/policy/distributed-solar/net-metering)

18 The savings is based on avoided energy costs in SDG&E's AL-TOU rate schedule.

19 The savings is based on avoided energy costs in PG&E's A-6 rate schedule.

Based on the 2013 EV Project report, the maximum charge power required by an EV was 50 kW[20], but these events occurred only 1 percent of the time. The vast majority of all other charging events required between 20 kW and 35 kW of power. Using the maximum value of 50 kW as a design criterion for an energy storage system, the authors can approximate a system cost of $55,000[21]. This energy storage system could provide various levels of demand reduction up to 50 kW and would have enough energy to offset up to 100 kWh of energy required for DCFC operations when combined with the PV generation. Using the same DCFC usage assumptions, this 100 kWh/50 kW BESS could effectively manage demand charges. The avoided demand charges based on $24/kW (SDG&E AL-TOU) could result in $480-$840 savings per month or $5,760 to $10,080 annually. On the other hand, the same system installed in PG&E territory and billed according to the A-6 tariff would see no demand charge offsets since there is no demand component to the A-6 rate schedule.

The high cost of implementing distributed energy resources (DERs)[22] remains a critical consideration, but there are incentives to help offset these costs. The federal investment tax credit (ITC)[23] for residential renewable energy is offered at 30 percent and could be leveraged to offset the PV costs. Moreover, the California Public Utilities Commission's Self-Generation Incentive Program (SGIP) offers an incentive of $1,460/kW for energy storage with a cap of 60 percent of project cost, and the utilities offer a net energy metering (NEM) program, although it will close by July 2017. If these credits and incentives are fully realized, the cost of the PV system could be reduced to $11,200 and the BESS to $11,000. The simple payback based on this analysis results in 11.2[24](SDG&E) years and 3.1[25] (PG&E) years for the PV system and 3.8[26](SDG&E) years for the energy storage system.

The above sections illustrated the economic benefit of PV and BESS applications, respectively. The integration of both PV and BESS to DCFC stations are increasingly desired as the system can provide a wider range of operational flexibility and reliability. Furthermore, independence from ever-increasing electric rates will improve the economic viability of DCFC operations in the long run by providing a form of insurance against possible future rate hikes. As the price of

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20 EV Project (http://avt.inl.gov/evproject.shtm)

21 Battery cost and resource: A BESS rated at 100kWh/50kW could cost about $55,000 based on an assumed cost of $550/kWh.

22 The California Energy Commission defines *distributed energy resources* as small-scale power generation technologies (typically in the range of 3 to 10,000 kilowatts) located close to where electricity is used (for example, a home or business) to provide an alternative to or an enhancement of the traditional electric power system

23 A taxpayer may claim a credit of 30 percent of qualified expenditures for a system that serves a housing unit in the United States that is owned and used as a residence by the taxpayer (See http://energy.gov/savings/residential-renewable-energy-tax-credit.)

24 This *return on investment* (ROI) is based on the avoided electric cost of $1,000 per year in SDG&E territory.

25 This ROI is based on the avoided electric cost of $3,600 per year in PG&E territory.

26 This ROI is based on the avoided demand cost of $5,760 per year in SDG&E territory.

DERs continues to decline, the authors anticipate that more vendors will integrate DERs with their DCFC stations to reap the value that they provide.

DCFC and Areas With Limited Utility Infrastructure

DCFCs proposed in remote areas may require additional considerations if the site lacks access to three-phase power. The cost of bringing three-phase power to a new location is costly; it can run from $15,000 to $30,000 per mile. Therefore, alternative options such as a single-phase system or off-grid systems combined with renewables and/or energy storage systems may make sense in certain critical corridors with limited electrical infrastructure.

Single-Phase Systems

DCFCs can be successfully integrated with renewable generation and energy storage, where three-phase power is available. The installation of renewables in an area without three-phase utility power is possible but presents several challenges. First, the cost of upgrading to three-phase power is high and may not be financially viable. The number and variety of equipment that can operate on single-phase power are also scarce. According to energy storage manufacturers, the technology exists to allow the simultaneous charging of batteries from both a renewable energy source and the electric grid. Commercial solutions are not presently available, however, that allow single-phase charging of a large-scale energy storage systems. Manufacturers agree that the primary reason for lack of single-phase compatibility is market demand. Most customers interested in energy storage are large commercial customers with available three-phase power or residential customers with PV systems that allow for DC charging of the battery systems.

All commercially available DCFC systems operate on three-phase power in the United States. A single-phase powered DCFC system may become available in the near future. Siemens/Efacec and Valent Power are developing a single-phase DC quick charger rated at roughly 24-30 kW. These quick chargers will be equipped with SAE combo or CHAdeMO connectors and are designed to be powered from either three-phase 208 volt or single-phase 240 volt at nearly 100 amps. The chargers are expected to obtain ETL/UL certification early 2016 and to become commercially available shortly thereafter. Furthermore, research organizations such as the Electric Power Research Institute (EPRI) have already started evaluating new technologies that will allow low-voltage DCFCs.

Off-Grid System

For areas with no access to utility infrastructure, self-contained vehicle charging solutions are now available on the market. These products are off-grid and combine solar PV with integrated BESS that is then connected to an electric vehicle through an EV charging unit. For example, SDG&E is proposing an off-grid system with solar canopies in Aliso Creek, where three-phase power is not available[27].

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27 PEV Infrastructure Proposal to California Energy Commission, SANDAG and Caltrans District 11.

When installing the energy storage and PV as an off-grid solution, they should be sized sufficiently large to provide a reasonable level of reliability. The cost of installing a reliable, independent off-grid DCFC system powered by solar and energy storage system can become significant but may be relieved, to some extent, by federal tax credits and state incentives.

CHAPTER 3:
Funding Requirements and Strategies

While it's clear that the fast charging infrastructure is needed to unlock the full potential of the EV market and connect urban centers, there is less enthusiasm about the business case in more remote and less traveled corridors. To this end, AESC will devise a framework that will act as basis for various business strategies and will suggest ways to compress the cost of operating the DC stations. A key element is the importance of stakeholder collaboration and alignment of objectives. There are many benefits that could result from DCFC station deployment beyond charging revenues.

Cost Parameters

The annual operation costs consist of the following parameters:

- Demand Charges: The demand components of electric tariffs can exceed $30/kW; EV tariffs like those in SCE territory have demand cost components of roughly $13/kW. If only Nissan Leafs charged at the proposed sites, the demand costs would be at least $400 per site; the annual demand costs per station if used just once a month will be about $4,800/year. A Tesla Model S would result in demand charges increasing to about $1,500 per month per site, with annual costs of about $18,000 per site.
- Energy Charges: The energy component of electric costs varies greatly by tariff and utility. Using the example EV tariff ($0.30/kWh) and EV (Nissan Leaf), the energy cost component of charging is about $7 per charge during summer on-peak period. If each of the proposed 60 DCFC sites had only one Leaf charge for just half of the year, the annual energy costs would be about $1,300/year/site.
- Meter Charges: ~$200/month per commercial meter.
- Annual Maintenance: $300-$3,000/year[28]
- Cost of Equity

Revenue Parameters

The revenue opportunities consist of the following parameters:

- Manufacturing and sales
- Operations and maintenance
- Installation
- Value-added services
- Energy premiums

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28 *Take Charge: A Roadmap to Electric New York City Taxis*, NYC Taxi and Limousine Commission, December 2013; UCLA Luskin Center Financial Viability of Non-Residential Electric Vehicle Charging Stations, Snyder, Chang, Erstad, Lin, Rice, Goh, Tsao, August 2012)

- Fee-based charging (per minute, per hour, per session): Typical $9-$15/hour ($0.15-0.25/minute) for DCFC – Service based on time rather than energy delivered
- Network fees
- Asset utilization
- Partnerships and sponsorships

Framework for the Business Structures

As mentioned earlier, the key to fostering healthy growth of the EV infrastructure market is an alignment of interests among the various stakeholders and market participants. Since there are numerous barriers to profitability in the remotely located DCFC infrastructure, innovative strategies to fill the DCFC station gaps need to be considered.

Constraints

Aside from the costs associated with operating the DCFC infrastructure, there are other constraints on profitability. The operational characteristics and low use of remotely located DCFCs limit meaningful revenue generation from charging alone. Additional restrictions may be placed on the for-profit models if, by chance, the proposed public DCFC stations are operated "free-of-charge."

Also, when electric infrastructure upgrades are necessary for DCFC installation, the costs can be prohibitive.

Cost Compression

A key to overcoming these financial gaps is cost compression. One particular strategy is the effective use of electric rates/tariffs. The statewide Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT)[29] tariff allows local governments to generate electricity at one account and transfer any available excess bill credits (in dollars) to another account owned by the same local government. The idea is to use existing or planned local government renewable generation to offset energy cost at DCFC sites. By addressing the energy-billing component of EV charging in this manner, more focus can be placed on demand management. In SDG&E's service territory, the DG-R tariff is offered to customers with distributed generation capacity that is equal to or greater than 10 percent of their peak annual load. When this occurs, it unlocks the benefit of lower demand and energy charges in the range of $12/kW and $0.05/kWh. In this scenario, a developer could install the required PV capacity at the DCFC site to gain access to these lower rates. Finally, EV charging tariffs are being introduced throughout the state and offer reduced demand billing components. These should be thoroughly examined alongside prevailing tariffs.

Partnerships

Partnerships are an effective way to highlight the benefits of multiple technologies and features. They are mutually beneficial and bring value such as access to new markets, better financing

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29 These RES-BCT tariffs allow local governments to generate electricity at one account and transfer any available excess bill credits (in dollars) to another account owned by the same local government.

terms, stronger buying power, and so forth. On the public side, a partnership in the DCFC infrastructure highlights a local government's willingness to participate in an innovative economy while addressing local economy needs and local climate action plans.

Along these lines, the DCFC infrastructure needs partnerships similar to the first gas stations that aligned shopkeepers and oil companies at the turn of the 20th century. In keeping with this well-established business model, eVgo partnered with Green Charge Networks (advanced energy storage manufacturer) to deploy energy storage systems at eVgo Freedom Stations. In a similar move, Panasonic teamed with Powertree to build solar/storage EV chargers that will be deployed throughout San Francisco.

Other partnerships include NRG eVgo and BMW, who are collaborating to provide expanded access to DCFCs in key markets throughout the country. Also, BMW and Volkswagen recently teamed up with Chargepoint to develop DCFCs along the East and West Coasts on certain corridors.

Clearly, as stakeholders consider the various market participants, they want to be aware of potential partnerships and remember that they are an excellent way to generate value beyond simple commodity transactions.

Identification of Market Participants and Roles

In this section, the authors introduce a common vocabulary for discussing various business cases. The market participants are outlined in Table 12 below. By providing a list of basic functions and market actors/stakeholders, the authors can more readily begin to identify ways to configure each of the parts into logical business structures.

Table 12: Key Market Participants

Owners/Site Hosts *Entities can play one or both roles*
State County Municipality/City Special Purpose Districts Commercial
Design/Construction Services *Engineering, design, and construction entities required to implement the project*
Main Contractor Project Manager System Designer Systems Integrator Installer
Equipment Services *Postinstallation the hardware and network will need to be serviced and maintained*
Maintenance Equipment Operators Network Operators Telecommunications
Administrative Services *Back-end support services*
Customer Services, Support, and Training Accounting Roadside Assistance Financial Management
Consumers *DCFC equipment will be used mostly by the following entities*
Individuals Company Vehicles Fleets Delivery Companies Emergency Law Enforcement
Site Type/Locations *Prospective/desired locations for the DCFC infrastructure*
Parks Rest stops Libraries Near Corridor Off/On-Ramps Commercial
Original Equipment Manufacturers *Participants also include OEMs of DCFC, vehicle, electrical equipment*

Business Structures

The following information describes example business structures for market participants involved in DCFC deployment. The authors have outlined the business structure, including project delivery and responsibilities, and pros/cons.

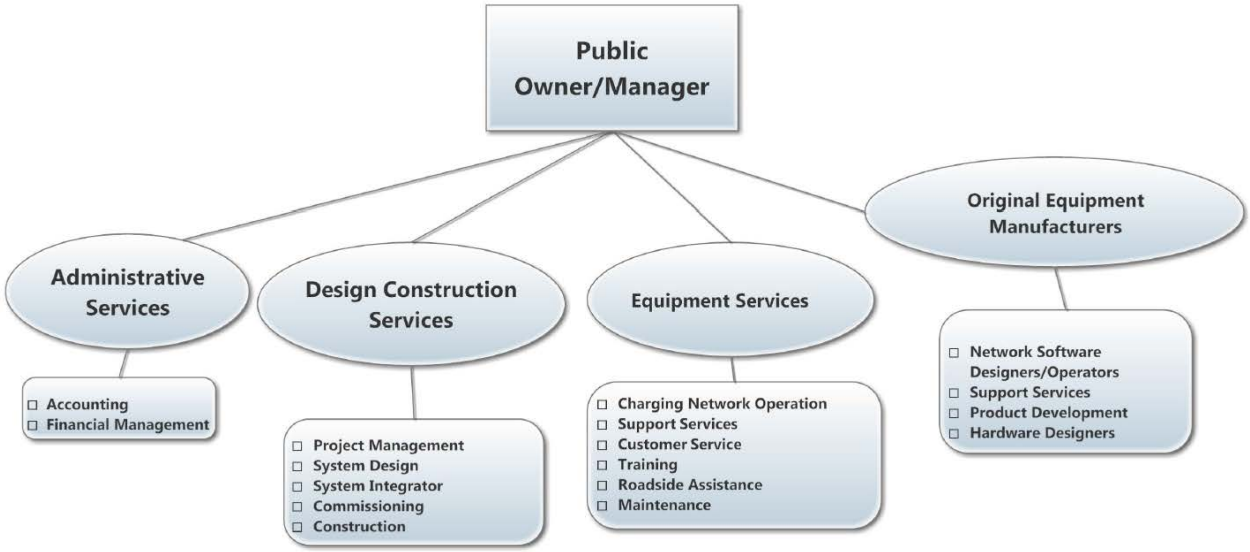
Public/Public

Business Structure

In Case 1, the ownership structure type is public/public. This means:

- The assets and site location are publicly owned.
- The nonprofit is the main point of contact that coordinates all of the efforts on behalf of the interested parties. The nonprofit:
    - Oversees development of projects.
    - Coordinates with counties and cities.
    - Obtains permits and other necessary approvals.
    - Manages day-to-day operations.
    - Needs to understand permitting requirements or at least be familiar with permitting processes.
    - If procuring utility services, needs to have interconnection experience.
    - Should have a good understanding of the EVs and EV infrastructure.
- In day-to-day operations, the nonprofit is supported in its efforts by the operators that perform the services mentioned in the previous section. The operator can be a single entity or multiple entities that specialize in the service provided.
- The project will be designed and built by a third-party entity selected by the owner or nonprofit.

Figure 6: Public/Public Organizational Chart



Source: *Alternative Energy Systems Consulting*

Pros/Cons

The pros of the public/public model include the following:

- The nonprofit takes on major overseeing role in lieu of the government(s).
- The nonprofit acts on government's behalf during procurement.
- There is potentially no fee to charge.
- It's mission driven.
- The nonprofit could create other opportunities for funding.

The cons for the public/public model include the following:

- It could be difficult to contract with an entity to provide all the needed operation services.
- The nonprofit could create inefficiencies in the process due to additional layer of oversight.
- The nonprofit may not be technically savvy.

Public/Private

Business Structure

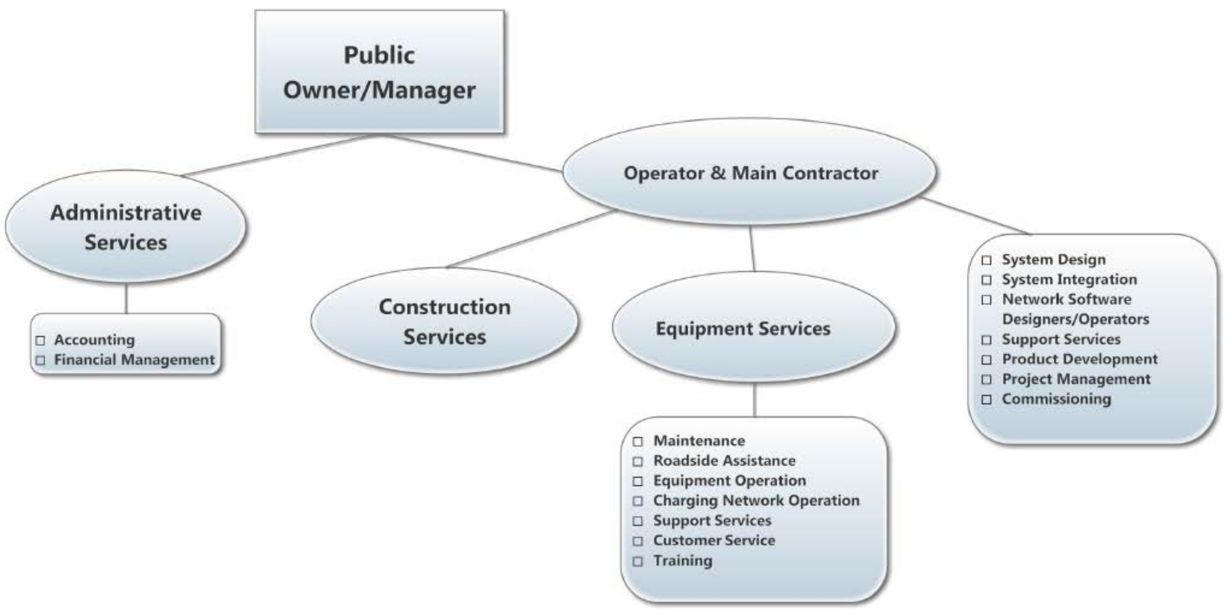
Business Case 2 is similar to Case 1, however, without the nonprofit. In this case:

- The public owns the asset.

- The main contractor operates of the EV stations. The operator/main contractor:
    - Oversees development of projects with government entity.
    - Coordinates with counties and cities.
    - Obtains permits and other necessary approvals.
    - Manages day-to-day operations.
    - Needs to understand permitting requirements.
    - Equipment operation, administration, and construction are performed by a separate company, but as a sub to main contractor.
- The project will be designed, built, and operated by a third party selected by the public owner.

This model is a replica of the structure used in Estonia's ELMO project.

Figure 7: Public/Private Organizational Chart



Source: *Alternative Energy Systems Consulting*

Pros/Cons

The pros of the public/private model include the following:

- The operator meets necessary technical prerequisites.
- It's the most streamlined business case.

- Government interacts directly with the operator, bringing closer alignment.
- Government procures the entire solution/infrastructure in a single transaction.
- There are centralized negotiations of utilities, sites, and approvals.
- There are streamlined planning and execution of project and phases.
- There is possible access to free charging through stakeholders (such as automakers).
- It's mission driven.

The cons for the public/private model include the following:

- It requires governments to manage extra efforts and could be burdensome.
- It could be difficult to contract with an entity to provide all the needed services.

Private/Private

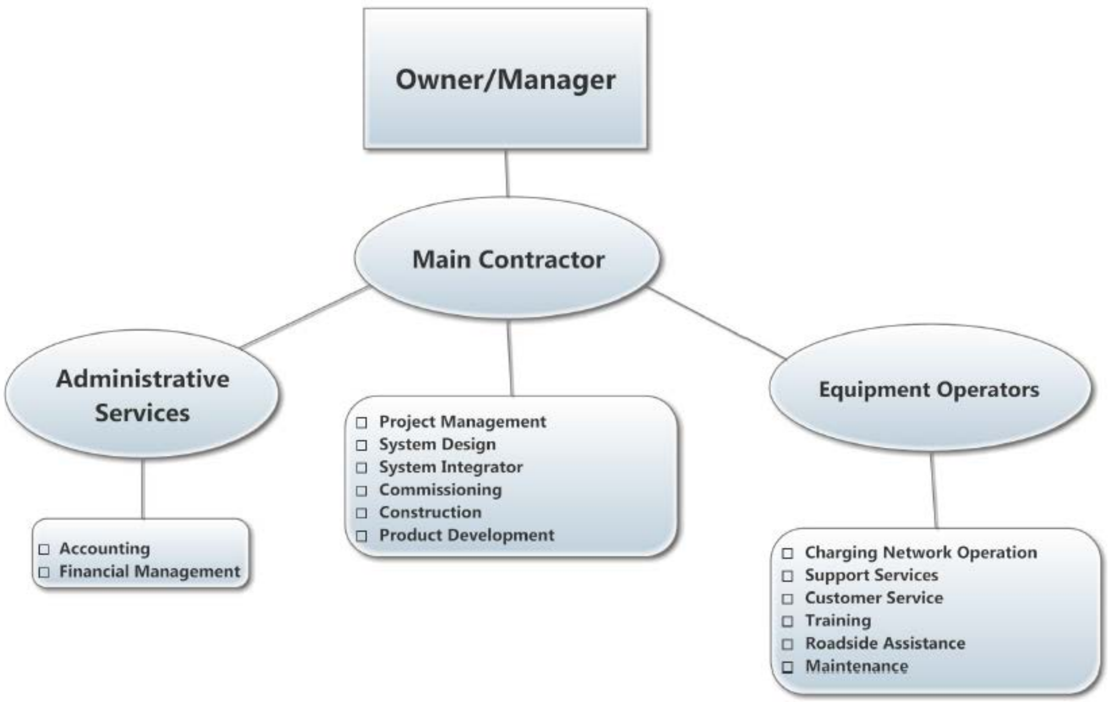
Business Structure

Case 3 is an all-private business structure. There is no local government ownership of asset or land. The assets and land lease deals are wholly controlled by the private entity that owns and operates the infrastructure. Partnerships may be developed to provide the various services required to manage and operate the infrastructure. The private operator:

- Oversees development of projects.
- Coordinates with counties and cities.
- Obtains permits and other necessary approvals.
- Manages day-to-day operations.

The project will be designed, built, and operated by a third party selected by the private owner.

Figure 8: Private/Private (Type 1) Organizational Chart



Source: *Alternative Energy Systems Consulting*

Pros/Cons

The pros of the private model include the following:

- The owner/operator meets necessary technical prerequisites.
- There is a streamlined business case.
- There are centralized negotiations of utilities, sites, and approvals.
- There are streamlined planning and execution of project and phases.
- A private entity is motivated to reduce costs as much as possible.
- The owner/operator procures the entire solution/infrastructure in a single transaction – in this case since the OEM is the owner, there are efficiencies that cannot be realized in other business cases, potentially driving down costs.
- After a period, the sites could become fee–based, and that transition would be more efficient without the government ownership of assets.

The cons for the private model include:

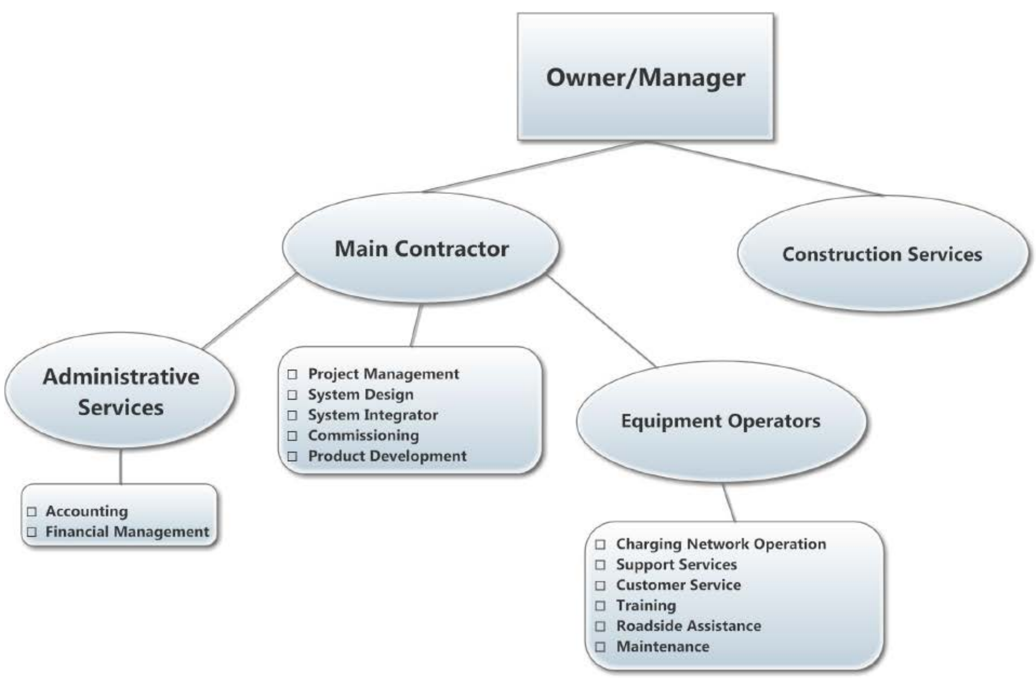
- Limited government interaction.
- Less oversight.
- Not mission driven.
- Infrastructure decisions made unilaterally.
- Service quality and decisions made unilaterally perhaps with cost-reductions in mind and not with quality of service in mind.
- Need to ensure that the owner is financially liable without the contract – company needs to last as long or longer then the asset.

Private/Private (Alternate Project Delivery)

Business Structure

Case 4 is also an all-private business structure. It is the same structure as Case 3 with an alternate project delivery. The owner/operator designs the project and puts the construction service out for bid. Since these are separate entities, the process needs to be managed.

Figure 9: Private/Private (Type 2) Organizational Chart



Source: *Alternative Energy Systems Consulting*

Pros/Cons

The pros and cons are the same as Case 3. The only additional con is the need for an additional level of management over the construction contractor.

Summary

The base case business structures described above illustrate the innovative ways various stakeholders can be aligned. Since projects will be implemented in various counties and cities, however, considerations are needed to encompass differences in permitting, utility requirements, and other factors. The EV Norway project[30], the ELMO[31], and the Netherlands ElaadNL/EVnetNL & FASTNED[32] infrastructures have all successfully implemented countrywide charging infrastructures. In each of these cases, the business strategies achieved the right balance of value while meeting the project objectives and connecting the interests of the stakeholders. For this reason, in lieu of recommending a specific business structure, the authors return to the original thesis, that alignment of interest is paramount to fostering growth of the DCFC infrastructure.

EV Norway

Norway has developed a charging infrastructure business model that is most similar to the public/private structures described earlier. The Norwegian government funds or cofunds investment in the infrastructure, and the private sector assumes the ownership and operating responsibilities Specifically, the charge points are developed by Transnova and several municipalities, registered in a national database called Nobil, and owned/operated by various market participants.

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30 (source: www.evnorway.no) EV Norway is the name given to the Norwegian national EV charging infrastructure. Today, EV Norway charging infrastructure consists of 6,557 charge points distributed throughout the country.

31 (source: Fast Charging Network for Electric Cars Project "ELMO" in Estonia - Steven Dorresteijn, ABB Group, 29 jan 13; elmo.ee) The Estonian Electricmobility (ELMO) Program is Estonia's effort at establishing a national grid of electric vehicle charging stations. Today, ELMO consists of nearly 163 chargers.

32 (sources: http://www.elaad.nl/organisatie/over-ons/about-us/; http://www.evnet.nl/organisatie/; http://www.fastned.nl/en) The Netherlands has arrived at its EV charging infrastructure in a slightly less concerted effort then the previous two examples. On one side there are organizations like ElaadNL and EVnetNL that are funded by a consortium of electric infrastructure OEM's. ElaadNL is the private entity that coordinates the deployment of public charging infrastructure and interconnection. EVnetNL provides management, maintenance and troubleshooting of the equipment. The ElaadNL/EVnetNL infrastructure boasts about 300 public charging stations.

ELMO

ELMO is another example of the public/private business model. In this case KredEx, a credit guarantee agency under the jurisdiction of the Ministry of Economic Affairs, owns, organizes and manages the support scheme for the EV infrastructure. ABB, an EV equipment manufacturer, bid and won a contract to supply, install, and commission the EV charging stations, as well as administer the system. ABB partnered with NOW! Innovations and G4S to provide complete systems and service operations.

Netherlands

On a slightly different path, there is FASTNED, which is also a private entity and has partnered with ABB and has installed 28 charge stations with multiple chargers at each station. Its goal is to install one station per week until it reaches at least 201 stations throughout the country. Interestingly, the FASTNED network is crowd-funded with 4 million shares outstanding, and each share can be purchased for 10 euro. The FASTNED stations have at least two fast chargers with all fast charging standards, free Wi-Fi, fully covered by solar-paneled roofs, security cameras, and multiple payment options. FASTNED runs all operations from beginning to end and is one of the few wholly contained EV infrastructure developers. A key component that makes the FASTNED plan viable is that it has already secured concession rights to realize and operate the 201 fast charging stations for 15 years.

Funding Requirements

As previously stated, making a profitable business case for DCFC is difficult, even in highly used areas. Without exception, all the entities contacted indicated that they would need the installation and equipment cost covered to site any of the corridor gaps where usage would be sparse at the onset. Most of the entities (EVSPs, governmental agencies, and regional bodies) indicated that they would need subsidies to support ongoing operations and maintenance. This was especially true of the not-for-profit entities. Some of the commercial entities indicated that they may be able to get subsidies from external sources such as the Nissan “no charge to charge” program. According to some sources, the sale of charge time covers only ~25-30 percent of the costs of operations. This varies widely based on the cost of electricity by utility and peak demand charges.

Installation and Equipment Costs

It’s difficult to estimate specific installation and equipment costs based on varying equipment configurations and site conditions. Experts interviewed estimate an installed cost of $50,000 to $100,000 for a typical DCFC station with at least two ports. Solar generation and battery storage add significantly to the cost of the installation. Some superstations including full battery storage, solar, and up to eight ports can cost from $250,000 to $1,000,000. However, after numerous conversations, AESC has determined an approximate figure of $140,000 to $215,000 per site for the recommended configuration options. This does not include solar or battery storage, but those additions should be considered separately.

Through the PEV Infrastructure workshop and subsequent contact, stakeholders have identified several grant funding scenarios, including first costs subsidy, operation and maintenance support, and site assessment support.

First Costs Subsidy

According to UCLA's Luskin Center and many other stakeholders, return on investment is marginal even at the most used sites. Using a model purely based on the income from the sale of energy, the margin between revenues and expenses is low, which makes recovering first costs difficult. The reality is that equipment and installation costs, while dropping, are still at very high levels. To make a business case for the more remote—and initially less used–sites, the site host will need assistance to cover the significant upfront costs. For instance, it is expected that most public/public and public/private entities would need installation and equipment cost to be fully covered to make an investment. The expert consensus on the "willingness threshold" indicates that initial capital costs need to be fully covered with little or no cost share.

Operation and Maintenance Support

Many of the public and quasi-public entities that AESC interviewed agreed that having operation and maintenance cost subsidized in the first couple of years would help the financial situation for smaller jurisdictions. There appeared to be a consensus, however, that operation and maintenance support was not critical. For instance, a small regional authority indicated that the operation and/or maintenance could be accounted for in public infrastructure funding.

Site Assessment Support

Several stakeholders suggested that public support could be best used in helping local jurisdictions defray the costs associated with site identification and assessment. While these are real costs and site selection is a real barrier to implementation, AESC feels that these are somewhat outside the scope of the intended focus of this effort. The hope is that the competitive nature of the process will yield proposing entities that have the necessary experience and wherewithal to develop a legitimate site assessment process. Moreover, the Energy Commission and other government entities have funded numerous studies with the various PEV regional readiness groups. Many of these studies go to great lengths to identify and rate potential sites.

Funding Summaries

It is AESC's recommendation that the Energy Commission consider covering installation and equipment costs with a small match requirement for less remote sites. The process should be used to encourage bidders to develop innovative ways to build a business case to support operation and maintenance (O&M). This could potentially take the form of teaming with outside entities such as automakers to provide subsidies or use advertising/marketing/social benefits to build the business case.

As described above, AESC recommends a $140,000 cap on the Option #1 configuration and a $215,000 cap on the Option #2 configuration. A 25 percent match funding requirement should be instituted for sites that are in less remote areas. Remote areas are determined as less than the 25,000 VMT/mile in the NREL visibility metric.

Table 13: Funding Recommendations by Corridor

Segment	Priority	Map Label	Section	WCEH Corridors	Approx. Miles	Additional Sites	Remote	Option #1 $	Match	Option #2 $	Match
WCEH 1	1	I-5 RBF:OR	North	I-5 Oregon to Red Bluff	142	7	Y	$980,000	$0	$1,505,000	$0
WCEH 2	1	I-5 SAC:RBF	North	I-5 Red Bluff to Sacramento	126	4	N	$420,000	$140,000	$645,000	$215,000
WCEH 3	1	99 SAC:FAT	Central	SR 99 Sacramento to Fresno	177	3	N	$315,000	$105,000	$483,750	$161,250
WCEH 4	1	99 FAT:GVN	Central	SR 99 Fresno to Wheeler Ridge	140	3	N	$315,000	$105,000	$483,750	$161,250
WCEH 5	1	I-5 GVN:SCT	South	I-5 Wheeler Ridge to Santa Clarita	56	3	N	$315,000	$105,000	$483,750	$161,250
WCEH Sub-Total (Only Including SR-99 through Sacramento and San Joaquin Valleys)								$2,345,000	$455,000	$3,601,250	$698,750

Segment	Priority	Map Label	Section	Corridors	Approx. Miles	Additional DCFC Needed	Remote	Option #1 $	Match	Option #2 $	Match
Other	1	580 DBN:TCY	North	I-205/I-580 Dublin to Tracy	39	1	N	$105,000	$35,000	$161,250	$53,750
Other	1	101 SJC:SMG	Central	US 101 San Jose to San Miguel	148	4	N	$420,000	$140,000	$645,000	$215,000
Other	1	80 SAC:RNO	North	I-80 Sacramento to Reno, NV	141	4	N	$420,000	$140,000	$645,000	$215,000
Other	1	50 SAC:LKT	North	US 50 Lake Tahoe to Sacramento	103	3	N	$315,000	$105,000	$483,750	$161,250
Other	1	120 OKD:YSM	Central	SR 120 Oakdale to Yosemite	90	3	N	$315,000	$105,000	$483,750	$161,250
Priority 1 Subtotal								**$1,575,000**	**$525,000**	**$2,418,750**	**$806,250**
Other	2	10 BMT:BLY	South	I-10 Beaumont to Blythe	148	4	N	$420,000	$140,000	$645,000	$215,000
Other	2	41 LMR:OKR	Central	SR 41 Lemoore to Oakhurst	79	2	N	$210,000	$70,000	$322,500	$107,500
Other	2	I-5 OSD:SCN	South	I-5 Oceanside to San Clemente	24	1	N	$105,000	$35,000	$161,250	$53,750
Other	2	I-15 SBO:NV	South	I-15 San Bernardino to Nevada	182	6	N	$630,000	$210,000	$967,500	$322,500
Other	2	14 SCT:INY	South	SR 14 Santa Clarita to Inyokern	119	4	N	$420,000	$140,000	$645,000	$215,000
Other	2	152 101:99	Central	SR 152 from US 101 to SR 99	83	3	Y	$420,000	$0	$645,000	$0
Other	2	58 BKR:LWD	South	SR 58 Bakersfield to Lenwood	126	4	Y	$560,000	$0	$860,000	$0
Other	2	10 SRA-EKA	North	US 101 Santa Rosa to Eureka	217	7	Y	$980,000	$0	$1,505,000	$0
Priority 2 Subtotal								**$3,745,000**	**$595,000**	**$5,751,250**	**$913,750**
Other	3	I-5 SAC:SCK	North	I-5 Sacramento to Stockton	49	1	N	$105,000	$35,000	$161,250	$53,750
Other	3	I-5 SCK:GVN	Central	I-5 Stockton to Grapevine	252	5	N	$525,000	$175,000	$806,250	$268,750
Other	3	99 SAC:RBF	North	SR 99 Red Bluff to Sacramento	132	5	Y	$700,000	$0	$1,075,000	$0
Other	3	12 FRF:LDI	North	SR 12 Fairfield to Lodi	47	1	Y	$140,000	$0	$215,000	$0
Other	3	49 AUB:GRS	North	SR 49 Auburn to Grass Valley	24	1	Y	$140,000	$0	$215,000	$0
Other	3	505 VCA:I-5	North	I-505 from Vacaville north to I-5	32	1	Y	$140,000	$0	$215,000	$0
Priority 3 Subtotal								**$1,750,000**	**$210,000**	**$2,687,500**	**$322,500**
Priority 1 through 3 Subtotal								**$7,070,000**	**$1,330,000**	**$10,857,500**	**$2,042,500**
Other	4	8 ECJ:YUM	South	I-8 El Cajon to Yuma AZ	158	5	Y	$700,000	$0	$1,075,000	$0
Other	4	86 IDO:ECR	South	SR 86 Indio to El Centro	86	3	Y	$420,000	$0	$645,000	$0
Other	4	395 HPA:NV	Central	US 395 Nevada Border to Hesperia	209	6	Y	$840,000	$0	$1,290,000	$0
Other	4	40 BSW:NED	South	I-40 Barstow to Needles	144	4	Y	$560,000	$0	$860,000	$0
Other	4	70 MVL:ORO	North	SR 70 Marysville to Oroville	39	1	Y	$140,000	$0	$215,000	$0
Other	4	88 SCK:CRC	North	SR 88 Carson City, NV to Stockton	127	4	Y	$560,000	$0	$860,000	$0
Other	4	36 RBF:FTA	North	SR 36 Fortuna to Red Bluff	132	4	Y	$560,000	$0	$860,000	$0
Other	4	70 ORO:395	North	SR 70 Oroville to US 395	136	4	Y	$560,000	$0	$860,000	$0
Other	4	18 AVL:LUC	South	SR 18 Apple Valley to Lucerne Valley	24	1	Y	$140,000	$0	$215,000	$0
Priority 4 Subtotal								**$4,480,000**	**$0**	**$6,880,000**	**$0**
Grand Total								**$11,550,000**	**$1,330,000**	**$17,737,500**	**$2,042,500**

Source: *Alternative Energy Systems Consulting*

CHAPTER 4: Recommendations

AESC recommends the following for Energy Commission consideration:

- ***Grant funding for identified corridor gaps.*** Existing DCFC infrastructure efforts are heavily concentrated in the urban areas. The authors recommend funding sites within corridor gaps that will initially be less commercially viable.
    - Consider CalEV Highway and "other" corridors separately to maintain the distinct goals set for the WCEH.
    - Fund sites along the "other" corridors based on the first three priority groups.
    - Construct a scoring system that gives preference to proposals that include higher priority sites. Proposals with multiple sites of different levels should be weighted accordingly.
- ***Grant funding levels.*** To adequately seed the infrastructure in the corridor gap regions, AESC calculates about 80 sites will require some form of public subsidies. Most PEV regional readiness personnel indicated that a grant covering full installation and equipment cost would be necessary to move forward. While most of the PEV stakeholders indicated that a grant covering O&M costs for the first couple years would be welcomed, it did not appear to be an absolute necessity. Several personnel indicated enough of a business case could be made to keep the chargers operational. AESC estimates it will require between $9.4 million and $14.5 million to adequately cover these costs for the CalEV Highway and Priority 1, 2, and 3 corridor gaps on the "other" corridors.
    - Provide between $9.4 million and $14.5 million for DCFC infrastructure funding.
    - Fund the full installation and equipment costs up to a maximum of $140,000 - $215,000 per site with a 25 percent cost share component for nonremote sites. The $140,000 cap on site funding should be for sites configured as Option #1 and $215,000 for sites that are configured as Option #2.
    - Increase the maximum award funding to $1 million per application to encourage commercial interests to combine corridor gap sites with a commercially sustainable site. This will help offset first costs for identified gap locations.
- ***Site requirements.*** The site must meet minimum requirements to satisfy the needs of the PEV client and the infrastructure goals. In general, the site must be safe, accessible, convenient, and reliable. These needs should be expressed as compliant/noncompliant in the process. The site should also contain a type and mix of charging stations that will maximize the usefulness of the site.

    - Enforce the minimum needs as laid out in the Site Requirements section, which will result in a pass/fail determination for the submitted proposals.
    - Require that each site includes:
        - Option #1 ($140,000 Cap)
            - One CHAdeMO DCFC charger
            - One dual-protocol DCFC charger
            - One Level II charger
            - One expansion location (for future use).
        - Option #2 ($215,000 Cap)
            - Two CHAdeMO DCFC chargers
            - Two dual-protocol DCFC chargers
            - One Level II, dual-port charger
            - One expansion location (for future use).

- ***Energy and demand management.*** It is recommended that the Energy Commission continue to encourage the integration of renewable generation and energy storage as DCFCs continue to be installed throughout California.
    - For sites with three-phase power available from the local utility, contractors should be encouraged to integrate renewable generation and energy storage into proposed DCFC solutions. However, the additional infrastructure should be considered on merit based on site conditions and needs.
    - At this time, locating a DCFC in an area without access to three-phase utility power is not a commercially available or economically viable solution. If a new technology solution is proposed, however, the Energy Commission should consider allowing the project under the higher cap value.
- ***Business structures.*** After reviewing numerous cases and real-world examples, a common theme emerged that suggests business structures can be relatively simplistic or complex as long as they meet the expectations of the parties involved.
    - All business structures should be allowed to participate. Prioritizing a particular model could have the effect of limiting innovative market structures, which are an effective way to highlight the benefits of multiple technologies and create value beyond simple commodity transactions.
    - Many of the DCFC sites may be in areas that have limited commercial activity. As a result, the public/public structure may provide the best solution. In these cases, the local government may need additional financial assistance to operate the site.

- Where infrastructure is located in economically challenged regions, the employment of local contractors and workers should be encouraged. The benefits of these types of efforts are the sharing of economies and leveraging the projects to promote the use of local developers and stimulating local economies.
- Using the most advantageous rates/tariffs should not be overlooked; cost compression is necessary for these sites, and therefore, the use of the most beneficial tariffs is imperative.
- The sponsorship model should be promoted to offset the ongoing costs of operating and maintaining the fleet of DCFC infrastructure.

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